MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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ExxonMobil Refining and Supply Company
Billings Refinery
S ½ of Section 24 and N ½ of Section 25, Township 1 North, Range 25 East, Yellowstone County
700 ExxonMobil Road, Billings, MT 59103

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 1-4, 5, 6/6C, 9, 10 & 11
Ambient Monitoring Required		X	Monitoring is being conducted on a voluntary basis under the auspices of BLAQTC
Continuous Opacity Monitoring System (COMS) Required	X		FCC carbon monoxide (CO) Boiler Stack, Coker CO Boiler Stack
Continuous Emission Monitoring System (CEMS) Required	X		CO, Hydrogen sulfide (H_2S), sulfur dioxide (SO_2), and after 12/2008 oxides of nitrogen (NOx)
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		In accordance with the Stipulation
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #1564-19
New Source Performance Standards (NSPS)	X		Subparts A, J, Kb, VV (as required by MACT CC) and GGG (subsumed)
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		
Maximum Achievable Control Technology (MACT)	X		Subparts CC and UUU. Subpart DDDDD is “State-only”
Major New Source Review (NSR)/Prevention of Significant Deterioration (PSD)	X		ExxonMobil is defined as a major source but has not yet triggered a PSD/NSR review
Risk Management Plan Required (RMP)	X		Submitted to EPA on 6/21/99
Acid Rain Title IV		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO_2 Control Plan

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit.

Conclusions in this document were based on information provided in the original application submitted by ExxonMobil Refining & Supply Company (ExxonMobil) on June 12, 1996; additional submittals on March 23, 2000, April 24, 2000, and April 25, 2000; a significant modification application submitted on August 21, 2000, with additional information submitted on November 13, 2000, and November 22, 2000; significant modification applications submitted on February 13, 2002, October 22, 2003, April 9, 2004, February 9, 2005, September 22, 2005, and October 5, 2005; Administrative Amendment requests dated January 11, 2006, April 5, 2006, and February 9, 2007; and the Title V renewal application submitted June 6, 2006.

B. Facility Location

The ExxonMobil Billings Refinery is located at 700 ExxonMobil Road in Billings, Montana. The Yellowstone River forms the northern and northeastern boundaries and interstate Highway 90 lies along the southern border. Refinery units and storage tanks lie in the southern half of Section 24 and the northern half of Section 25 of Township 1 North, Range 25 East in Yellowstone County. The Montana Rail Link railroad tracks transect the refinery product storage tanks lying south of the railroad right-of-way and the remainder of the refinery lying north of the tracks. The active refinery occupies approximately 380 acres on a level plot with an elevation of approximately 3091 feet (Mean Sea Level). ExxonMobil Road, which provides access to the refinery, is paved. Parking lots and roadways within the active portion of the site are also paved. The refinery lies east of the Billings City Limits in an area zoned Heavy Industrial. A 5- to 7-foot high chain link fence, topped with 1 foot of three strands of barbed wire and 24-hour guards provide security.

C. Facility Background Information

The Exxon Company U.S.A Billings Refinery (Exxon) requested a modification to **Permit #1564A2** to support the Yellowstone Energy Limited Partnership (YELP) permit. The permit modification was given **Permit #1564-03**. That request was addressed under the provisions of Subchapter 7, Administrative Rules of Montana (ARM) 17.8.733(1)(b) (now ARM 17.8.764). Exxon proposed to do the following in conjunction with the YELP permit: (1) send all coker process gases to YELP for treatment; (2) change the manner in which the refinery-wide sulfur-in-fuel emission limitation is calculated (daily to hourly) for all fuel-burning units; (3) change the 1.1 pounds per million British thermal units (lb/MMBtu) sulfur limit to 0.96 in order to provide sufficient offsets for the YELP facility; (4) cap the refinery fuel oil burning at 720 barrels per day any time YELP is operating both of its boilers; and (5) provide additional verification of sulfur dioxide emission reductions by the addition of recording devices on the Coker Carbon Monoxide Boiler (KCOB) fuel oil-firing unit and storage fuel oil system, and by utilizing the present emission calculation/ accounting procedures at the refinery.

The projected operational changes in Exxon's permit would reduce SO_2 emissions into the Billings air shed. This reduction takes place as a result of the coker process gas emissions, which include SO_2, CO, coke fines, reduced sulfur compounds and oxides of nitrogen (NO_x) being sent to YELP for treatment. This is discussed further in the YELP permit analysis.

In addition, Exxon proposed no fuel oil burning in the KCOB any time YELP is operating two boilers, plus a commitment to adhere to an hourly sulfur-in-fuel limitation on a refinery-wide basis when YELP is operating both of their boilers.

Adherence to an hourly sulfur-in-fuel limitation has been changed from 1.1 to 0.96 lbs. of sulfur-in-fuel per million Btu's fired. This change has been equated to a 100-ton-per-year offset based on actual SO_2 emissions for the past 2 years. In addition, Exxon has committed to a daily refinery fuel oil consumption cap of 720 barrels any time YELP is operating two boilers. This condition was insisted upon by the EPA because of the difficulty in meeting the federal definition of federally enforceable emission limits. Logic suggests that if the YELP facility operates as expected and provides the anticipated steam load to Exxon, a larger reduction in SO_2 emissions would actually be realized because of reduced fuel oil firing at the refinery.

It was critical for both YELP and Exxon to coordinate their activities closely once operation of YELP commenced. The Exxon proposal was based on information attached to Permit #1564-03 which more fully explains the 100-ton-per-year figure and also the rationale for the block hourly 0.96 lbs. of sulfur-in-fuel figure calculated on a refinery-wide basis.

Exxon requested that the Department of Environmental Quality (Department) consider revising the permit when the new 213-foot stack at Montana Sulphur and Chemical Company (MSCC) is constructed and made federally enforceable. This increase in stack height decreases MSCC's ambient impacts and could decrease the required offset at Exxon for YELP. The Department agreed to provide the opportunity for such a revision. However, before Exxon's sulfur-in-fuel limit could be increased, the new 213-foot stack must be made federally enforceable through a modification of MSCC's air quality permit. Further, the Department believed the increased stack height may be necessary to address concerns with the current SIP and, therefore, may not be available to reduce the required emission offset at Exxon.

On November 12, 1994, Exxon was issued **Permit #1564-04** to construct and operate an 800-ton/day Polymer Modified Asphalt (PMA) unit. The PMA unit allows Exxon to produce polymerized asphalt. Conventional asphalt base stock is mixed with solid polymer pellets in a wetting/mixing tank, ground with a shear mill, and returned to the PMA storage tank. The PMA is then loaded out through existing stubs at the west rack. No additional steam demand or fuel consumption was necessary for the PMA project. Volatile Organic Compound (VOC) emissions were the primary pollutant of concern; however, all VOC emissions from equipment and tanks in asphalt service were assumed to be negligible since asphalt has negligible vapor pressure at the working temperature seen in the unit.

This alteration also addressed Exxon's August 9, 1994, modification request to replace the strip recorder of the tank gauging device on the fuel oil storage system with a data transmission system inputting to a data acquisition system (DAS). The modification allowed Exxon to use the computer system to collect and archive the fuel data to meet permit conditions.

On August 25, 1995, Exxon was issued **Permit #1564-05** for a stack extension to the D-4 Drum Atmospheric Vent stack constructed in July 1993. The stack extension raised the height of the D-4 Drum Atmospheric Vent stack from 40.8 meters (134 feet) to 70.1 meters (230 feet). In addition, steam injection capability was added to raise the effective height of the stack to 79.2 meters. The stack extension was designed to eliminate refinery worker exposure impacts during emergencies.

The D-4 Drum Atmospheric Vent is a safety device used to control and manage both routine and abnormal releases from process units. A limited number of safety valves and intermittent blowdowns from the crude, hydrofiner and coker units are vented to this drum. Inside the drum, a continuous flow of water cools any safety valve releases or blowdowns to condense vapors for subsequent treatment in the wastewater treatment plant. Any vapors not condensed, exit through the D-4 Drum Atmospheric Vent stack.

On January 14, 1996, Exxon was issued **Permit #1564-06** to construct the Fluid Catalytic Cracking (FCC)/CO Boiler stack extension from 63.4 to 76.7 meters and the F-2 Crude/Vacuum Heater stack from 63.6 to 65 meters. As part of the 1995 proposed Billings/Laurel SO_2 State Implementation Plan, Exxon and the Department stipulated that Exxon shall extend the heights of the F-2 Crude/Vacuum Heater and FCC/CO Boiler stacks to at least 65 meters. Exxon was allowed to raise these stacks to above 65 meters, but will receive a Good Engineering Practices (GEP) credit for modeling purposes of 65 meters. Exxon shall be entitled to a greater GEP credit for either stack if a physical demonstration (fluid model or field study) is conducted and justifies a taller GEP stack height.

On June 17, 1996, the Department issued **Permit #1564-07** to modify the opacity limitations for the wetting/mixing tank exhaust vent in the PMA unit. The requirements of 40 CFR 60, Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, were reviewed during the initial permit review and it was determined that this Subpart was not applicable to the wetting/mixing tank because the tank is used for mixing only and does not store asphalt; therefore, it does not meet the definition of a storage tank. The opacity limit set in the original permit was representative of an asphalt tank used for storage of asphalt as defined under 40 CFR 60, Subpart UU. However, the permitted opacity limit did not recognize the fact that mixing asphalt is occurring in the mixing tank. Due to mixing, there may be a noticeable opacity at the wetting/mixing tank top, even when mixing temperatures are well below 400º F.

A 20% opacity limit was set to reflect the effects of minor mixing in the wetting/mixing tank, which is consistent with ARM 17.8.304 (2). This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere, from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

Exxon still needs to maintain the operating temperature of the wetting/mixing tank below the smoking point of the asphalt in order to comply with a 20% opacity limit. The wetting/mixing tank only operates intermittently during the summer asphalt season. Any opacity is localized inside the refinery and does not create a public nuisance.

On July 7, 1999, Exxon was issued **Permit #1564-08** to bring the permit closer to the requirements of the June 12, 1998, Stipulation between Exxon, the Department, and the Board of Environmental Review. The proposed changes reduced the reporting and recordkeeping burden for both Exxon and the Department, updated the permit with current rule references, and consolidated all the previously issued permits to Exxon in Permit #1564-08. The specific changes to the permit and consolidated permits are outlined in the permit analysis section of Permit #1564-08.

On August 21, 2000, Exxon submitted a permit application to the Department, with additional submittals on November 13, 2000, and November 22, 2000. The submittals requested the following changes to Permit #1564-08:

1. Addition of one new furnace (F-1201) with a firing capacity of 99 million British thermal units per hour (MMBtu/hr) or less;

2. Allow for the modification of furnace F-700 to increase its firing capability from 105.6 MMBtu/hr to 122 MMBtu/hr; and

3. Modification to the method of operation of Tank 26 to reduce volatilization of the stored petroleum product.

Several other administrative changes were made during this permit action. The following changes were incorporated into this permit, as well:

1. Removal of condition II.E.7 (Odors), based on ARM 17.8.717, from Exxon's permit, so it remains solely state enforceable.

2. A name change from Exxon Company U.S.A. to ExxonMobil received January 7, 2000).

3. Clarification of new operating temperature used in Section II.E.1. The description of the operating temperature was changed from "minimum operating temperature" to "operating temperature of the wetting/mixing tank below the smoking point of asphalt."

4. Reorganization of Section II of the permit.

5. Attachment of the letter dated September 25, 1989, which specifies the monitoring procedures (Appendix A) to be used for the permit (the above letter was previously referenced for monitoring procedures).

The requirements contained in Section II, Parts B and C, concerning an hourly limitation on sulfur in fuel and a daily limitation on fuel oil firing, respectively, apply on a refinery-wide basis to all fuel-burning units at the refinery, consistent with the 1977 Stipulation. **Permit #1564-09** reflected all of the above changes and replaced Permit #1564-08.

Permit #1564-10 was not issued. Two applications were received within the same time period to alter Permit #1564-09 and were not issued in the order in which they were received. To avoid confusion in referencing these permit applications and actions, Permit #1564-10 was removed from use.

On March 3, 2001, the Department issued a permit for the installation and operation of two temporary aero-derivative jet engine electricity generators (Model LM1500), each capable of generating approximately 10 megawatts of power, and an accompanying diesel storage tank. These generators were necessary because of the high cost of electricity. The operation of the generators would not occur beyond 2 years and was not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

Because these generators would only be used when commercial power was too expensive to obtain, the amount of emissions expected during the actual operation of these generators was minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, ExxonMobil was not required to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, ExxonMobil was responsible for complying with all applicable air quality standards. As these generators were temporary, the Title V permit was not modified to include them. **Permit #1564-11** replaced Permit #1564-09.

On May 16, 2001, the Department issued a permit for the installation and operation of a temporary aero-derivative jet engine electricity generator (Model LM1500), capable of generating approximately 10 megawatts of power. This generator would be used in addition to the two similar generators permitted in Permit #1564-11 and would be considered a part of the same project with respect to time constraints. This generator and the two generators previously permitted are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

As previously mentioned, because the generators will only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of the generators is minor. In addition, the installation of the generators qualifies as a "temporary source" under the PSD permitting program because the permit will limit the operation of the generators to a time period of less than 2 years. Therefore, ExxonMobil will not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. In addition, ExxonMobil is responsible for complying with all applicable air quality standards. Again, as this generator was temporary, the Title V permit was not modified to include it. **Permit #1564-12** replaced Permit #1564-11.

ExxonMobil was issued a final and effective Title V permit on December 2, 2001 (**Permit #OP1564-00**).

On February 13, 2002, the Department received a permit application to address emission increases associated with the proposed modifications to allow approximately 500 barrels per day more fresh feed to be processed through the Fluid Coker unit (Coker). Other units/processes that would be affected by the proposed modifications include the FCC Unit, the motor gasoline (mogas) storage tank throughputs, and the refinery fuel gas system throughput. Included in this permitting action is a limit on refinery-wide fuel oil combustion used to keep the overall SO_2 emissions increase from the project below the PSD of Air Quality SO_2 significance levels. In addition, a contemporaneous decrease in VOC emissions on Tank #309 would offset the increase in VOC emissions from the project, to keep the project below PSD VOC significance levels.

The project involves the following activities (not all of them requiring permitting, but all included in the application as they relate to the overall project):

1. Replace the existing product coke line with a larger diameter pipe and remove a number of bends and turns to decrease piping pressure drop. Line size will increase from 6 inch to 8 inch in diameter and allow for a product coke capacity of approximately 550 tons per day. This line connects from the Coker unit to the BGI coke silo (capacity related);

2. Upgrade the gearbox of the Coker light ends compressor to facilitate compressing the increased volume of light ends from the higher throughput at the Coker. This compressor (C-311) is located in the refinery Gas Compressor Building near the north end of the FCC Unit facility (capacity related);

3. Install new steam aeration nozzles and replace appropriate sections of the scouring coke line from the Coker burner to the reactor. This will allow improved coke circulation and avoid excessive coke buildup at the Coker area (maintenance related);

4. Install a multi-hole orifice chamber in the Coker Process Gas line that goes to either BGI or the Coker CO Boiler. This device stabilizes the back-pressure that the slide valves, located on the top of the Coker burner vessel, will have to control. This device will allow smoother transition in unit operations whenever the Coker Process Gas must be diverted away from BGI and back to the Coker CO Boiler (maintenance and capacity related);

5. Modify the cyclone outlet from the Coker reactor to the scrubber section to a newer design, which has a custom designed elbow and larger horn (outlet), decreasing the velocity and pressure drop through the cycle to accommodate an increased vapor rate. The cyclone is located at the top of the Coker reactor outlet and carries reactor hydrocarbon vapors into the scrubber section of the vessel (capacity related);

6. Modify the internals of the D-202 Coker Fractionator Overhead receiver drum to improve liquid/vapor separation. This drum is located at the Coker unit (capacity related);

7. Modify the Coker reactor feed pumps and drivers to increase capacity to match the 500 barrel per day unit increase and higher discharge pressure requirements. The reactor feed pumps take oil from the scrubber and recycle this liquid back to the feed surge drum and supply the reactor feed nozzles. By increasing the speed of the pump impellars, both pressure and increased capacity requirements are satisfied without having to replace the pumps. The bearing housings will be upgraded, if necessary, to safely achieve these higher speeds (capacity related);

8. Modify the reactor feed nozzle system with an improved design. The intent of these changes will be to optimize the Coker unit feed nozzle system operation (capacity related); and

9. Include adequate safety facilities to address safety concerns at the higher Coker unit capacity. This may include replacement of some vessel nozzles and connecting piping to upgrade metallurgy or refractory linings such that higher operating temperatures could be achieved. This may also include the installation of larger safety valves and associated piping (capacity related).

Permit #1564-13 replaces Permit #1564-12.

Operating Permit #OP1564-01 incorporated the changes made to the Montana Air Quality Permits (MAQP, formerly preconstruction) #1564-09 and #1564-13. As mentioned above, Permit #1564-10 was not issued. Permits #1564-11 and #1564-12 involved temporary sources, and, therefore, the Title V permit was not updated to include those sources. In addition, upon review of Operating Permit #OP1564-00, the Department discovered that an applicable requirement from the MAQP was not included in the Title V permit. That requirement (a 0.96 lb/MMBtu limit on sulfur in the refinery fuel gas) has been superseded by other requirements listed in the permit, but is still applicable, and needs to be included. Operating Permit #OP1564-01 was issued final and effective on July 20, 2004 and replaced Operating Permit #OP1564-00.

On October 22, 2003, the Department received a MAQP Application from ExxonMobil to modify Permit #1564-13 to meet the EPA 15 parts per million (ppm) sulfur standard for highway diesel fuel. On December 4, 2003, the Department deemed the application complete. Units/processes that were affected by the proposed modifications included the Kerosene Hydrofiner (Hydrofiner No. 3), Diesel Hydrofiner (Hydrofiner No. 1), new facilities to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, and modifications and additions to facilities to segregate highway and off-road No. 2 diesel fuels. The modifications resulted in an increase in throughput through the FCCU and an increase on motor gas (mogas) production. This permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 emissions increase from the project would stay below the PSD SO_2 significance levels. The permit action took out all references to the temporary generators that were previously permitted and were removed from the facility. The equation for Tank 26 was updated to more accurately account for temperature and pressure in the calculation of VOC emissions for Tank 26. **Permit #1564-14** replaced Permit #1564-13.

On April 9, 2004, the Department received a MAQP Application from ExxonMobil to modify Permit #1564-14 for changes in how ExxonMobil planned to meet the EPA's 15 ppm sulfur standard for highway diesel fuel. Units/processes affected by the proposed modifications included the addition of a lubricity facility and the addition of minor piping. ExxonMobil no longer planned to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, or to segregate highway and off-road No. 2 diesel fuels. The current modification resulted in an increase in throughput through the FCC Unit, an increase in mogas production, an increase at the Hydrogen Unit, and an increase in throughput at the marketing terminal. The permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 and particulate matter (PM) emissions increase from the project would stay below the PSD SO_2 and PM significance levels. **Permit #1564-15** replaced Permit #1564-14.

On February 9, 2005, the Department received a complete MAQP Application from ExxonMobil to modify Permit #1564-15. The purpose of the application was to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allowed for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The modifications directly affected F-551 and, potentially, indirectly increased throughput to the FCC Unit, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput did not increase as a result of the modification. The permitting action resulted in lowering the existing limit on refinery-wide fuel oil combustion so that the overall SO_2 and PM emissions increase from the project was be below the PSD SO_2 and PM significance levels. Section II.F.2 of the Permit Analysis (Permit #1564-16) included a discussion of the netting analysis conducted for the permit action. **Permit #1564-16** replaced Permit #1564-15.

On September 22, 2005, the Department received a complete MAQP Application from ExxonMobil to modify Permit #1564-16. Further information was received in a letter from ExxonMobil dated October 20, 2005. The purpose of this application was to address several projects impacting the PMA unit. ExxonMobil proposed modifications to the PMA process unit and addition of a new PMA railcar loading in order to create more PMA from a historical production rate of 300 – 600 barrels per day, to 5000 barrels per day PMA, and to allow PMA loading of railcars. In addition, on October 19, 2005, the Department received a request for an Administrative Amendment to allow the use of Method ASTM D1298 for determining the API gravity of fuel oil. These permit actions were combined**. Permit #1564-17** replaced Permit #1564-16.

On October 5, 2005, the Department received a MAQP Application from ExxonMobil to incorporate the following emergency stationary engines into Permit #1564-17: five existing diesel-fired engines; one new diesel-fired engine; and two existing gasoline-fired engines. After receiving additional submittals from ExxonMobil, the Department determined that the application was complete on February 17, 2006. **Permit #1564-18** replaced Permit #1564-17.

The Department received two de minimis notifications and two administrative amendment requests from ExxonMobil. The administrative amendment was issued May 8, 2007, in response to these four requests:

- 12/22/05 – Catalytic Hydrotreater Unit – Billings (CHUB-Amine) and FCC Unit de minimis notification (no permit changes required).
- 1/11/06 – Administrative Amendment request to eliminate fuel oil monitoring requirements, based on elimination of fuel oil firing at the refinery;
- 4/5/06 – Administrative Amendment request to incorporate Consent Decree requirements; and
- 2/9/07 – De minimis notification for addition of Selective Catalytic Reduction (SCR) to FCC Unit/CO boiler and treat Sour Water Stripper (SWS) overhead to meet Consent Decree requirements (no permit changes required).

Section II of the permit was also reorganized and extraneous permit conditions were eliminated. **Permit #1564-19** replaced Permit #1564-18.

D. Current Permit Action

On June 6, 2006, the Department received an application for the renewal of Title V Operating Permit #OP1564-01. The application was deemed administratively complete on July 6, 2006, and technically complete on August 7, 2006. Operating Permit #OP1564-02 incorporates all applicable source changes since the issuance of Operating Permit #OP1564-01, including:

- Consolidation of all refinery fuel gas combustion requirements into a new EU00;
- Addition of a Refinery-wide fugitive emitting unit EU17;
- Elimination of all emitting units that have no applicable requirements, other than facility-wide applicable requirements (EU02, EU05, EU-06, EU07, EU08, EU10, EU11, EU12, EU13, EU16);
- Addition of a new emergency stationary engine EU18; and
- Inclusion of all Consent Decree requirements.

On December 3, 2007, Exxon appealed Operating Permit #OP1564-02 on the basis of the inclusion of the entire Consent Decree CV-05-C-5809. The Department included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below) satisfy both Exxon and the Department with respect to inclusion of Consent Decree requirement into the Title V Operating Permit. Exxon will continue to pursue the necessary permitting action as necessary to comply with the requirements of the Concent Decree.

ExxonMobil has entered into a Consent Decree (United States et al v. Exxon Mobil Corp., CV-05-C-5809 (N.D. Ill. Dec. 13, 2005)). Certain consent decree emission limits, standards, and schedules have been incorporated as applicable requirements into the appropriate sections of this permit. Other consent decree requirements, *including program enhancements, are not required by the Consent Decree to be incorporated into this permit as permit coniditons and are thereby not included as applicable requirements in this permit.* These terms and conditions may only be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the Consent Decree. This summary is intended for convenient reference only and the actual language of the Consent Decree governs the terms and conditions that are enforceable through the Consent Decree.

Operating Permit #**OP1564-02** replaces Operating Permit #OP1564-01.

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 105, MCA, the Department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications. The checklist was completed on July 17, 2007.

F. Compliance Designation

The last full compliance evaluation of ExxonMobil Refinery was conducted on September 22, 2005. ExxonMobil was found to be in compliance with the limits and conditions of Montana Air Quality Permit #1564-18 and Title V Operating Permit #OP1564-01 at the time of the inspection.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

ExxonMobil operates a greater than 52,000 barrel per day petroleum refinery designed to process high sulfur crude oil. Major processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
2. Fluid Catalytic Cracking Unit
3. Hydrocracker/Hydrogen Plant
4. Fluid Coker
5. Naphtha Fractionator
6. Catalytic Reformer
7. Hydrofluoric Alkylation Unit
8. Three Hydrotreaters for polishing the distillate streams
9. Catalytic Hydrotreater Unit – Billings (CHUB Unit)

ExxonMobil does not have a sulfur recovery unit at this refinery. Refinery gases high in H_2S are piped to an off-site sulfur recovery plant owned and operated by MSCC. MSCC has an Amine unit to treat the sour fuel gas and return the sweet refinery fuel gas to ExxonMobil.

The refinery and the adjacent ExxonMobil bulk terminal are considered one facility for the purpose of any permitting completed in accordance with the New Source Review Program. In addition, according to EPA and Department interpretations, ExxonMobil's bulk terminal is considered a "support facility" for the refinery, and is therefore part of a Title V major source. At the request of the company, the bulk terminal will be permitted separately under the Title V operating permit program.

B. Emission Units and Pollution Control Device Identification

EU00: RFG – including 12 heaters & boilers not otherwise listed

This emitting unit incorporates all of the facility-wide refinery fuel gas requirements (including 40 CFR 60, Subpart J limitations, and requirements for monitoring, testing, recordkeeping and reporting). This emitting unit also includes the facility-wide Stipulation SO_2 limitations. Compliance is demonstrated for the 40 CFR, Subpart J requirements through use of a H_2S CEMS on the refinery fuel gas (RFG) header. Compliance is demonstrated for the lb/hr Stipulation limitations through use of a RFG fuel gas flow meter in addition to the H_2S CEMS.

<u>EU1b: F-3 Heater Stack</u>. This unit is a process heater that heats crude for the oil fractionation process.
<u>EU2a: F-3x Heater Stack and EU2b F-5 Heater Stack</u>. These units are process heaters that heat naphtha and/or distillates for the desulfurization process.
<u>EU3b: F-202 - Heater Stack</u>. This unit is a process furnace that super heats used steam in the fluid coking process.
<u>EU4a: F-700 Heater Stack</u>. This unit is a process heater that heats naphtha for the reforming process.
<u>EU5a: F-402 Heater Stack</u>. This unit is a hot oil heater that heats a circulating diesel material used to exchange heat to other hydrocarbons for fractionation and other process heating requirements.
<u>EU7a: F-201 Heater Stack</u>. This unit is a process heater that heats distillates and hydrogen for the desulfurization process.

EU11a: F-651 Heater Stack. This unit is a process heater that heats feedstock for the hydrocracking process.
EU12a: F-551 Heater Stack. This unit is a gas-fired, steam-reforming heater that contains a catalyst and manufactures hydrogen.
EU13a: B-8 Standby Boiler House Stack. This unit is a steam boiler.
EU14b: F-10 Stack – Heater. This unit is a gas-fired storage tank heater which heats circulating oil. This unit fires only sweetened fuel.
EU16a: F-1201 Heater Stack. This unit is a process heater in support of the low sulfur motor gasoline process. This stack is required to have ultra low NO_x burners.
EU03a: Coker CO Boiler (KCOB) and EU09a: FCCU CO Boiler (CCOB) are included under the RFG requirements of this section, but are also regulated under individual emitting units.

EU01: Crude – Atmospheric Pipe Still (APS) and Vacuum Pipe Still (VPS)

The #1 Crude unit fractionates or separates petroleum crude oils into fractions including gas, naphtha, distillate, gas oil and residuum, with the lightest molecules at the top of the APS fractionating tower and the heaviest molecules at the bottom of the tower. The heavy "bottoms" from the first fractionation tower (APS) are further fractionated in a vacuum tower (VPS).

EU1a: F-2 Crude Vacuum Heater (F-1 Crude Furnace/ F-401 Vacuum Heater). This unit is a process heater that heats crude and reduced crude oil for the fractionation process.
EU1c: D-4 Drum Atmospheric Stack. This unit is a safety device to control and manage both routine and abnormal process unit releases.

EU02: HF #2/3 – Hydrofining Units #2 & #3 – *this EU was eliminated since the heaters are now included under EU00.*

EU03: Coker - Fluid Coker

This unit thermally cracks residuum into materials including gases, naphtha, gas oils and coke using a fluidized coke. The primary control is the YELP process.

EU3a: KCOB - Coker CO Boiler. This unit is a steam boiler, which may burn coker process gases in addition to supplemental fuel. There is an opacity and stack flow and SO_2 CEMS monitors on this stack.
EU3c: Coker Process Gas Vent. Collection of Group I Miscellaneous Process Vents.

EU04: Catalytic Reforming (POFO – Powerforming) Unit

This unit reforms low octane naphtha into high-octane gasoline using a catalyst.

EU05: Alky/Splitter/Rerun/Diene - Alkylation Unit, Alky Feed Treater, Rerun of Alkylate for Avgas – *this EU was eliminated since the heaters are now included under EU00.*

EU06: Treater - Cat Naphtha Caustic Treater (Merox Unit) after Cat Cracker – *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17.*

EU07: HF#1 - *this EU was eliminated since the heaters are now included under EU00.*

EU08: DEC2 - Deethanizer Unit - *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17*

EU09: FCCU - Catalytic Cracking Unit

This unit catalytically cracks heavy petroleum gas oils into lighter materials including gas, naphtha, olefins, and cycle oils using a circulation bed of fluidized catalyst.

EU9a: CCOB - FCC CO Boiler. This unit is a steam boiler, which may burn catalytic cracking process gases in addition to supplemental fuels. This stack has both an opacity monitor and an SO_2 CEMS.
EU9b: CCOB Bypass.

EU10: ULEB/SLEB - Unsaturated Light Ends Unit, Saturated Light Ends Unit, Sour Water Strippers, Gas Compression - *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17*

EU11: HCBL - Hydrocracking Unit - *this EU was eliminated since the heaters are now included under EU00.*

EU12: H_2 Plant/HRUB - H_2 Plant, H_2 Upgrade (Recovery) Facility, MDU Replacement - *this EU was eliminated since the heaters are now included under EU00.*

EU13: Utilities - Air Compressors/Dryers, Boiler Feed Water - *this EU was eliminated since the boilers are now included under EU00.*

EU14: OM&U - Oil Movements & Utilities
This unit consists of the flare system

EU14a: Flare and Turnaround Flare. This unit is a flare for combustion of emergency gaseous hydrocarbon releases. The Turnaround flare is used only when the primary flare is not operating.
EU14c: Flare Seal Drum. This unit is a Group I Miscellaneous Process Vent.

EU15: OM&S/PMAU - Oil Movements & Shipping/Asphalt PMAU

This unit includes petroleum storage tank farms and the PMA unit. All non-unit specific storage tanks are included in this unit, which consists of about 80 tanks of various sizes and four spheres and four horizontal propane storage vessels.

EU15a: PMA Loading

EU16: Low Sulfur MoGas - *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17*

EU17: Refinery-Wide Fugitive Emissions

This new unit includes all VOC, HAPs and benzene equipment leaks throughout the facility.

EU18 – Emergency Stationary Engines

EU18a: SE1-SE6, IEU6a & IEU6b: 6 diesel and 2 gasoline emergency engines.

C. Categorically Insignificant Sources/Activities

Insignificant emission units under Title V are defined under ARM 17.8.1201(22) to mean any emissions unit with the potential to emit less than 5 tons per year (TPY) of a regulated pollutant, 500 TPY of lead, and 500 lbs/yr of hazardous air pollutants (HAPs); and is not regulated by an applicable requirement, other than a generally applicable requirement.

Appendix A of Operating Permit #OP1564-02 lists insignificant emission units at the facility. ExxonMobil is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix A.

Emission Unit ID	**Description**
IEU01	Warehouse building heater
IEU02	Mechanical building heater
IEU03	Operations Control Center building heater
IEU04	FCCU/HCBL Shelter heater
IEU07	Laboratory building heater
IEU08	Laboratory equipment testing emissions
IEU09	Gasoline knock engines (3)
IEU10	Main office building heater
IEU11	Trailer heating units (8)
IEU17	Propane odorant facility

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V operating permit were established by ExxonMobil's MAQP #1564-19, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, and MACT requirements. The definitions of terms apply to where the limit or condition was derived from. If a condition is placed in the permit from the SIP, then the definition that applies to that condition would be the SIP definition.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods required under applicable requirements are contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, ExxonMobil may elect to voluntarily conduct compliance testing to confirm its compliance status.

All requirements to perform any type of test in this permit were previously established by ExxonMobil’s MAQP #1564-19, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, and MACT requirements, except for the requirement to perform test on the FCC CO boiler and the Coker CO boiler. This permit requires Method 9 tests (as required by the Department and Section III.A.1) and biannual Method 5 tests to be performed on the FCC CO boiler and the Coker CO boiler. These testing requirements were established by the Department’s testing policy.

D. Recordkeeping Requirements

ExxonMobil is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emissions unit and Section V of the operating permit "General Conditions" explains the reporting requirements. ExxonMobil is required to submit quarterly, semi-annual, and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must also include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annul and annual reports instead of resubmitting the information in monthly, quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on August 3, 2007. The Department provided a 30-day public comment period on the draft operating permit from August 3, 2007, to September 4, 2007. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received by September 4, 2007, have been summarized, along with the Department's responses, in the following table.

Summary of Public Comments for #OP1564-02

Person/Group Commenting	Comment	Department Response
	No public comments were received.	

G. Draft Permit Comments

Summary of Permittee Comments for #OP1564-02

Permit Reference	Comment No.	Permittee Comment	Department Response
Section I	1, 2	Update responsible official information as noted.	Operating Permit changed as requested.
Section II	3	Add EU03a Coker CO Boiler (KCOB) and EU09a FCCU CO Boiler (CCOB) as sources subject to applicable requirements in EUOO.	Operating Permit changed as requested.
Section II	4, 5	Add MACT UUU under Pollution Control Device/Practice for EU04 and EU09 and add NSPS J under EU09.	Operating Permit changed as requested.
Section III.A.1 & III.A.2	6, 7	Consider consolidating Condition A.1 into Section V.R. and Condition A.2 into Section V.S.	The Department does not agree to this request. These requirements have been consistently specified in all the refinery permits.
Section III.A.14	8	Consider revising Condition A.14 as suggested.	The Department agrees to remove 40 CFR 61, Subpart J and V from this condition, since it is addressed elsewhere in the permit, and to modify the benzene waste operations requirement as suggested. The Department does not agree to remove the reference to the asbestos NESHAPS, since it is not specifically mentioned elsewhere in the permit, and for consistency with other refinery permits.

Section III.A.15	9	Request to delete Condition A.15, because ExxonMobil stated that the regulations do not require the submission of SSM plans.	The Department denies this request, since the request of SSM plans is allowed by 40 CFR 63.6(e)(3)(v) and for consistency with other refinery permits.
Section III.A.16	10	Request to consolidate Condition A.16 into Section V.X.	The Department denies this request, since this requirement is not specifically mentioned elsewhere in the permit, and for consistency with other refinery permits. The condition was reworded to reflect ExxonMobil's specific situation.
Section III.A.17	11	Request to consolidate Condition A.17 into Section V.AA.	The Department denies this request, for consistency with other refinery permits.
Section III.A.24 and A.27	12	Request to remove Conditions A.24 and A.27, Consent Decree requirements. Verbal request to clarify that this requirement pertains only to the Billings Refinery.	The Department does not agree that Section III.A.24 and III.A.27 should be removed from the permit. The intent of the Title V operating permit program is to record all of the air quality requirements that apply to a source in one document. The terms and conditions listed in Section III.A.24 and III.A.27 should remain in the permit, because the Consent Decree is an applicable requirement as defined by ARM 17.8.1201(10) and it contains relevant terms and conditions as required under ARM 17.8.1211(1)(c). The Department clarified that this requirement was relevant only for requirements effecting the Billings Refinery.
Section III.A.	13	Request to add a facility-wide condition for retaining records for 5 years, and removing it from the individual emitting units.	Operating Permit changed as requested.
Section III.	14	Request to remove redundant conditions.	The Department denies this request, for consistency with other permits and to maintain the transparency of requirements within individual units.
Section III.	15	Request to revise wording to reflect "monitor and report" rather than certify for specified conditions.	The Department changed most of the conditions, as requested.
Section III.B.	16	Add EU03a and EU09a to the EU list of process heaters.	The Department agrees to this request. These boilers are regulated under individual process heaters; however, the facility-wide fuel burning requirements also apply to these sources.
Section III.B. (as specified)	17	Remove conditions relating to 40 CFR 63, Subpart DDDDD ("Boiler MACT"), since the Court of Appeals for the District of Columbia vacated and remanded the rule on 7/30/07.	Currently, the State of Montana requires facilities to comply with 40 CFR 63, Subpart DDDDD, because ARM 17.8.342 incorporates by reference federal rules as of July 1, 2005 (see ARM 17.8.102). The reference for these conditions were changed to "state only."
Section III.B.6	18	Revise condition as noted.	Operating Permit changed as requested.
Section III.B.20	19	Revise condition as noted.	Operating Permit changed as requested.
Section III.B.21	20	Revise Condition B.21 and consolidate with Condition B.26, as noted.	Operating Permit changed as requested.
Section III.B.23 & III.D.13	21	Correct Conditions, to reflect MAQP.	Operating Permit changed as requested.

Section III.B.26	22	Remove Condition B.26, by consolidating with B.21.	Operating Permit changed as requested.
Section III.B.38	23	Revise Condition B.38 by striking word "these".	Operating Permit changed as requested.
Section III.B.44	24	Correct reference in Condition B.44.e to III.B.6.	Operating Permit changed as requested.
Section III.C.3	25	Revise Condition C.3 to reflect "during periods when SWSOH are burned in the F-1 Crude Furnace."	The Department denies this request; the condition, as written, reflects the Billings/Laurel SO_2 plan requirements under Section 3.(2)(a) and (b). Note that Condition C.9 only requires monitoring while SWSOH is being burned. Further clarification with ExxonMobil led to the removal of Condition C.7, as the RFG monitoring is covered in Section III.B.
Section III.C.9	27 (no comment 26)	Correct reference in Condition C.9 to III.C.3.	Operating Permit changed as requested.
Section III.D.14	28	Remove Condition D.14	Operating Permit changed as requested. ExxonMobil monitors compliance with the SO_2 limit through the CEMS required under the next condition, not RFG.
Section III.D.15, D.16 & D.17	29	Consolidate and revise Conditions D.15, D.16 and part of D.17. ExxonMobil is currently required to install the SO_2 CEMS.	Operating Permit changed as requested.
Section III.D.17	30	Revise Condition D.17 by consolidating the first part with the previous condition and keeping only the second part.	Operating Permit changed as requested.
Section III.E.1 and III.F.4	31, 32	Consider removing Conditions E.1 and F.4, which identifies 40 CFR 63, Subpart UUU as an applicable requirement for these two EUs.	The Department denies this request since it is a valid condition and does not increase any regulatory burden for ExxonMobil.
Section III.F.3 and Section III.F.23	33	Consider clarifying that SO_2 is not a 40 CFR 60, Subpart J applicable requirement under Condition F.3 and F.23.	Further discussion with ExxonMobil indicates that Condition F.17 accurately represents the applicable requirements for each pollutant. ExxonMobil's comment was merely to request that the Department clarify Conditions F.3 and F.23. The Department feels that the current condition is adequate, and does not plan to revise these conditions at this time.
Section III.F.5	34	Revise statement to allow for inclusion of all PM sources in a single compliance demonstration.	The Department denies this request. The ability to consolidate the compliance demonstration is specified only for the fuel burning sources under ARM 17.8.309, not process PM under ARM 17.8.310. Source testing protocol could address plant-specific testing issues in greater detail.
Section III.H.2 and III.H.24	35	Revise Conditions to reflect that Tank #40 is no longer subject to NSPS Kb, and Tank 11 is now subject.	Operating Permit changed as requested.
Section III.H.17 and III.H.27	36	Delete conditions requiring log of type of asphalt.	The Department denies this request; Title V Operating Permits must have compliance determinations and recordkeeping for each condition. The Department did reword the condition.
Section III.I.1	37	Revise the condition to clarify that NSPS Subpart VV does not apply to the refinery, and other clarifications.	Operating Permit changed as requested.
Section III.I.2	38	Revise the condition to clarify that equipment leak standards are subsumed into MACT CC.	Operating Permit changed as requested.

Section III.I.3	39	Revise to clarify.	Operating Permit changed as requested.
Section IV	40	Revise to reflect that MACT DDDDD has been vacated	See Comment #17 – this condition is now "state only."
Section IV	41	Add 40 CFR 60, Subpart IIII – to Table IV.B. for EU18	Operating Permit changed as requested.
Section IV	42	Add 40 CFR 60, Subparts Cc, Cd, K, Ka, and 60.474(e).	Operating Permit changed as requested.
Section IV	43	Revise table to show Tank 40 is excluded and Tank 11 is now subject to NSPS Kb.	Operating Permit changed as requested.
Section IV	44	Add F-1 and F-401 to list of process heaters exempt from Db and Dc Also, verbal request to remove 40 CFR 60, Subpart IIII from the table of facility-wide non-applicable requirements.	Operating Permit changed as requested.
Section V	45	Revise V.Ee to include "stipulations, orders, or consent decrees" as part of the definition.	Operating Permit changed as requested.
Appendix A	46	Delete IEUs 13 & 14; they are mobil sources and non-road engines, which are not regulated by Title V.	Operating Permit changed as requested.
Appendix D	47	Replace Appendix D with the proposed Appendix D provided with renewal application	Operating Permit changed as requested.

Summary of EPA Comments for #OP1564-02

Permit Reference	EPA Comment	Department Response
	No comments were received from EPA.	

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

A. Requirements Not Identified as Non-Applicable

Pursuant to ARM 17.8.1221, ExxonMobil requested a permit shield for all non-applicable regulatory requirements and regulatory orders identified in Section IV of the June 1, 2006, Title V Renewal application for Operating Permit #OP1564-02. In addition, that application also requested a permit shield for both the facility and for certain emission units. The Department has determined that the requirements identified in the permit application for the individual emission units are non-applicable. These requirements are contained in the permit in Section IV – Non-applicable Requirements.

The following table outlines those requirements that ExxonMobil had identified as non-applicable in Permit Application #OP1564-02, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason for Not Including
Administrative Rules of Montana (ARM)	
ARM 17.8.316 Incinerators ARM 17.8.770 Additional Requirements for Incinerators	The Department considers flares to be incinerators, and as such ExxonMobil is subject to ARM 17.8.316 and ARM 17.8.770.
ARM 17.8.322(2) – (4) Sulfur Oxide Emissions – Sulfur in Fuel	This rule may not be applicable to the source at this time; however, it may become applicable during the life of the permit.
Billings/Laurel SO_2 Control Plan (approved into the SIP by EPA on May 2, 2002 and May 22, 2003)	
Exhibit A §3(E)(1) -3(E)(3), 4(C), 4(D)(2), 4(F), 4(G), 6(B)(4)(b), 6(B)(7), 7(B)(1)(j)	The Department does not have the authority to change the applicability of the SO_2 SIP through this Title V action.
MAQP #1564-18	
Conditions #II.A.3, II.A.5, II.A.6, II.A.7, II.G, II.M.5, II.M.10, II.N.2, II.N.4, II.O.3 (F-700, only), II.O.4 (F-700 only), II.O. Notification required.	Since the Title V permit renewal application was submitted on June 6, 2006, the Department has issued a more recent MAQP #1564-19. The issues raised in Section IV.A. have all been removed from the permit and this comment is no longer relevant.

B. NSPS Standards

The following NSPS standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 60, Subparts D, Da, Db and Dc Standard of Performance for Steam Generating Units	ExxonMobil's boilers were not constructed, reconstructed, or modified after the applicability date for Subpart Db, and do not have the maximum size design capacities to meet the relevant thresholds for Subparts D, Da, or Dc. In addition, "process heaters" are not regulated as "steam generating units" and are not subject to this regulation.
40 CFR 60, Subpart UU Standard of Performance for Asphalt Roofing Manufacture	This standard is not currently applicable because potentially affected facilities were constructed prior to the applicable date of the regulation of May 26, 1981. However, this standard will be applicable upon modification of Tank #55 to asphalt service, as permitted under MAQP #1564-18.

Applicable Requirement	Reason Not Applicable
40 CFR 60, Subpart VV Standard of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	This requirement is not applicable because ExxonMobil does not operate affected facilities. However, ExxonMobil is required to comply with specific provisions within Subpart VV, as required under 40 CFR 63, Subpart CC.
40 CFR 60, Subpart XX Standard of Performance for Bulk Gasoline Terminals	These standards are not applicable to this permit because ExxonMobil Refinery is permitted separately from the bulk terminal (although they are considered to be one source for the purposes of New Source Review permitting). However, it is applicable to the ExxonMobil Bulk Terminal, permitted under preconstruction Permit #2967-00.
40 CFR 60, Subpart QQQ Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems	These standards are not applicable because affected facilities have not been constructed, modified, or reconstructed since May 4, 1987.

C. NESHAP Standards

The following NESHAP standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 61, Subpart Y National Emission Standard for Benzene Emissions From Benzene Storage Vessels	These standards are not applicable because ExxonMobil has no benzene storage.
40 CFR 61, Subpart BB National Emission Standard for Benzene Emissions From Benzene Transfer Operations	These standards are not applicable because ExxonMobil has no benzene transfer facilities.

D. MACT Standards

The following MACT standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 63, Subparts F, G, H & I National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks	The requirement is not applicable because the refinery is regulated under 40 CFR 63 Subpart CC.
40 CFR 63, Subpart Q National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	These standards are not applicable. ExxonMobil does not operate industrial process cooling towers that use chromium-based treatment of chemicals.
40 CFR 63, Subpart R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	These standards are not applicable to this permit because ExxonMobil Refinery is permitted separately from the bulk terminal (although they are considered to be one source for the purposes of New Source Review permitting). However, it is applicable to the ExxonMobil Bulk Terminal, permitted under preconstruction Permit #2967-00.
40 CFR 63, Subpart EEEE, NESHAPs: Organic Liquids Distribution (non-gasoline) except for initial one-time notification	ExxonMobil operates a toluene transfer rack what does not require controls; therefore, there are no requirements other than initial one-time notification.
40 CFR 63, Subpart ZZZZ: NESHAPs: Emergency Reciprocating Internal Combustion Engines (RICE)	All stationary RICE at ExxonMobil are rated < 500 brake horse power and are therefore not subject to Subpart ZZZZ.
40 CFR 63, Subpart GGGGG NESHAPs: Site Remediation	Since site remediation activities at ExxonMobil are being performed under RCRA corrective action and meets the exemption from Subpart GGGGG, ExxonMobil is not currently subject to the requirements in this Subpart.
40 CFR 63, Subpart LLLLL NESHAPs: Asphalt Processing and Asphalt Roofing Manufacturing	Subpart LLLLL does not apply to any equipment that is subject to 40 CFR 63, Subpart CC and 40 CFR 60, Subparts K, Ka & Kb, therefore, ExxonMobil is not subject to any requirements in this regulation.

E. Streamlined Requirements

Pursuant to ARM 17.8.1212, as of the date Operating Permit #OP1564-02 is issued, the federally-enforceable standards, monitoring, recordkeeping, reporting and other applicable requirements cited in the following table for the listed source or group of sources are subsumed by the more stringent requirement or by a “hybrid” compliance demonstration scheme. The Department has determined that compliance with the streamlined requirements listed below and elsewhere in this permit will assure compliance with the substantive provisions of the subsumed requirements.

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB) • EU14a (Flare and T/A Flare)	ARM 17.8.322(4) Sulfur in Fuel - Liquid and Solid Fuel limited to 1 lb sulfur per million Btu fired.	ARM 17.8.749, Consent Decree paragraph 60: ExxonMobil not capable of combusting solid fuel, and is not allowed to fire fuel oil, except during periods of natural gas curtailment, and except for (i) the use of torch oil in an FCC Unit Regenerator to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance; or (ii) combustion of acid-soluble oil in a combustion device.	Compliance with 40 CFR 60, Subpart J and not firing fuel oil will ensure compliance with the more generous subsumed rule.
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB) • EU14a (Flare and T/A Flare)	ARM 17.8.322(5) Sulfur in Gaseous Fuel – 50 grains/100 cubic feet (1,144 milligrams H_2S/dry standard cubic meter fuel (mg H_2S/dscm fuel))	40 CFR 60, Subpart J: 230 mg H_2S/dscm fuel (equivalent to 0.10 grains/dscf or ~160 ppmv H_2S @ STP)	The 40 CFR 60, Subpart J fuel sulfur (as H_2S) limit is much more stringent. Compliance with the NSPS limit assures compliance with the subsumed limits.
	Refinery-wide block hourly fuel sulfur limit of 0.96 lb/MMBtu fired (13,234 mg H2S/dscm fuel at a minimum RFG HHV of 810 Btu/scf)		
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB)	Billings/Laurel SO_2 Control Plan (Exhibit A), Section 6(B)(3)	Hybrid Statement: NSPS Subpart J continuous monitoring (Fuel gas H_2S CEMS – §60.105(a)(4) and §60.13; and flow rate monitoring CEMS – Billings/Laurel SO_2 Control Plan (Exhibit A), Section 6(B)(8).	The RFG H_2S CEMS required by 40 CFR 60, Subpart J meets or exceeds the performance specifications for the Fuel gas H_2S CEMS required by continuous monitoring provisions of the Billings/Laurel SO_2 Control Plan (Exhibit A, Section 6(B)(3). The redundant RFG H_2S CEMS is eliminated.
	Billings/Laurel SO_2 Control Plan (Exhibit A), Section 5 Emissions Testing: §5(B) Annual Source Testing Method 11 or equivalent.	Annual RATA (Method 11)	The annual source testing requirement is not necessary, as the annual RATA (Method 11) meets this requirement.

EU17 – Equipment Leaks Refinery-Wide	40 CFR 60, Subpart GGG; 40 CFR 61, Subparts J and V	40 CFR 63, Subpart CC (Petroleum Refinery MACT Rule)	Process units refinery-wide are subject to equipment and work practice standards, test methods and procedures, monitoring, recordkeeping and reporting requirements for equipment leaks set out in the Petroleum Refinery MACT Rule, which are at least equivalent or more stringent than the equipment leak standards and provisions of NSPS and NESHAPS.
EU15 – Group 1 Storage Vessels (Crude oil, gasoline, and petroleum distillate tanks > 65,000 gallons capacity)	ARM 17.8.324(1) – Hydrocarbon emissions – Petroleum products		All tanks with a storage capacity > 65,000 gallons and storing crude oil, gasoline, or distillates with a vapor pressure of 2.5 psia (17.2kPa) or greater are classified as Group I storage vessels, which are subject to the more stringent Petroleum Refinery MACT Rule.

SECTION V. OTHER PERMIT CONSIDERATIONS

A. MACT Standards

The Department is not aware of any additional proposed or pending MACT standards that may be applicable.

B. NESHAP Standards

As of October 31, 2007, the only NESHAP standards that the ExxonMobil refinery is currently subject to include Subpart M – Asbestos, Subpart J, Subpart V, and Subpart FF - Benzene Waste Operations. The Department is unaware of any proposed or pending NESHAP standard that may be applicable to ExxonMobil.

C. NSPS Standards

The Department is not aware of any proposed or pending NSPS standards, in addition to those already listed, that may be applicable at this time. However, ExxonMobil will be subject to applicable requirements in the proposed modifications to 40 CFR 60, Subpart J and proposed 40 CFR 60, Subpart Ja (proposed May 14, 2007), once finalized. In addition, ExxonMobil will be subject to any applicable changes to 40 CFR 60, Subpart VV (proposed November 7, 2006).

D. Risk Management Plan

Facilities exceeding the threshold quantities of regulated substances in a process were required to comply with 40 CFR 68 requirements no later than June 21, 1999. Facilities must comply within 3 years after the date on which a regulated substance is first listed under 40 CFR 68.130, or the date on which a regulated substance is first present in more than a threshold quantity in a process; whichever is later.

Because ExxonMobil exceeds the minimum threshold quantity for several regulated substances listed under 40 CFR 68.115, ExxonMobil was required to submit a Risk Management Plan to EPA by June 21, 1999. ExxonMobil submitted the plan to EPA on June 21, 1999.

The refinery has several regulated flammables such as propane, butane, etc. In addition, the refinery uses and/or processes anhydrous ammonia, aqueous ammonia (>20%), hydrofluoric (HF) acid and hydrogen sulfide, which are also regulated substances. Although the anhydrous ammonia, aqueous ammonia (>20%), and hydrogen sulfide are present in amounts less than the threshold quantities, ExxonMobil treats them in the same way by applying the accidental release prevention and the emergency response programs.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emissions of the applicable regulated air pollutant that are greater than major source thresholds.

ExxonMobil currently has one emitting unit that meet all the applicability criteria in ARM 17.8.1503: EU03 KCOB (Coker Unit CO Boiler). The unit is required to meet the process weight rule for PM. A multiclone is used for PM control. ExxonMobil proposes to use opacity monitoring as the on-going method of assuring compliance.

SECTION VI. OTHER CONSIDERATIONS

The Department has reviewed the refinery and ExxonMobil's bulk marketing terminal and has determined that for the purposes of New Source Review permitting, these facilities are one source. The refinery and the bulk marketing terminal are contiguous and adjacent, under common ownership and control and the terminal is a support facility to the refinery. Because the facilities meet these criteria, they meet the definition of source and will be considered one source under the requirements of ARM 17.8.749 and ARM 17.8.801(7). The emissions from both facilities will need to be considered when either facility makes a change.